PREPARED REMARKS
Q4/YEAR END 2016
MARCH 3, 2017

Ed Vamenta – Atlantic Power Corporation – Director, FP&A

Slide 2: Cautionary Note Regarding Forward-Looking Statements

Financial figures that are presented in this document and the presentation are stated in U.S. dollars and are approximate unless otherwise noted.

Management's prepared remarks presented in this document include forward-looking statements. As discussed on Slide 2 of the accompanying presentation, these statements are not guarantees of future performance and involve certain risks and uncertainties that are more fully described in our various securities filings. Actual results may differ materially from such forward-looking statements. Please see Atlantic Power Corporation's Safe Harbor statement, presented on Slide 2 of the accompanying presentation, which can be found in the Investor Relations section of our website.

In addition, the financial results in the Company's press release and the presentation include both GAAP and non-GAAP measures, including Project Adjusted EBITDA. For reconciliations of this measure to the most directly comparable GAAP financial measure to the extent that they are available without unreasonable effort, please refer to the press release, the Appendix of the presentation or our annual report on Form 10-K, all of which are available on our website.

For additional information, please refer to our most recent SEC filings, which can be accessed free of charge on our website, www.atlanticpower.com, and on EDGAR and SEDAR.

James J. Moore, Jr. – Atlantic Power Corporation – President & CEO

Slides 4-5: 2016 Progress Report

In 2016, we made considerable progress in reducing our leverage and reshaping our maturity profile. In April, we refinanced our term loan and revolver, gaining additional flexibility and extending the maturity dates of both. Although the upsizing of the term loan resulted in an increase in debt, by yearend this had been mostly offset by other debt reduction. We ended the year at 5.6 times levered. We remain committed to further delevering, and as evidence of this commitment, we plan to repay another $150 million of debt in 2017.

We continued to improve our cost structure. Continued debt repayment has had a very favorable impact on our cash interest payments, which declined $29 million in 2016 or $60 million from 2013 levels. We reduced overhead expense 28% in 2016, or 58% from 2013.

Our liquidity of $204 million includes about $50 million of discretionary cash, even after using nearly $20 million in 2016 to repurchase 8 million shares at an average price of $2.42. We plan to use $40 million or more of this cash for the additional debt reduction in 2017 that I mentioned. Settlement of our claims with respect to the NUG lawsuit in Ontario and a potential sale of Piedmont would add significantly to the $50 million of discretionary cash on hand.

Our 2016 cash from operating activities was $112 million, which was in line with expectations, although our Project Adjusted EBITDA of $202 million came in below our guidance due to lower water flows at Curtis Palmer, lower waste heat and severance costs that we recorded in the fourth quarter.

We initiated 2017 guidance for Project Adjusted EBITDA of $225 to $240 million, which represents a significant increase from the 2016 level. The increase is mostly attributable to the expiration of an above-market gas contract in Ontario at yearend 2016.

We completed the major projects in our optimization program. Including a modest investment this year, we will have invested a total of $27 million since 2013. We expect to realize a cash return on these investments of approximately $12 million in 2017.

Our work over the past two years in strengthening the balance sheet, improving our cost structure, addressing our debt maturity profile and increasing our liquidity puts us in a better position to withstand an extended downturn in a highly cyclical business.

Dan Rorabaugh – Atlantic Power Corporation – SVP, Asset Management

Slide 6: Q4 2016 Operational Performance

We had no recordable injuries in the fourth quarter, and two relatively minor ones for the full year. Our total recordable incident rate for the year was 0.7, which was below the industry average, which includes much larger companies for which the rate tends to be lower than for smaller companies such as ours. The 2016 result also represented an improvement from the previous year. We place the highest priority on maintaining a strong culture of safety and regulatory compliance.

The operational factors that affected fourth quarter results were continued low water flows at Curtis Palmer and lower waste heat in Ontario. The lower water flows at Curtis Palmer, which began in the second quarter, continued into the fourth quarter due to drought conditions in the region. Above-average precipitation so far this year has resulted in higher generation. Waste heat declined by approximately two-thirds from the fourth quarter of 2015, mostly due to geographical shifts in supply and demand for gas that have reduced the need for our waste heat units. Results in these two areas were below our expectations. In addition, we had a scheduled maintenance outage at Oxnard in the fourth quarter and turbine maintenance expense at Kapuskasing and North Bay.

Our availability factor of 93% for the fourth quarter was modestly below the 96% a year ago. Planned and unplanned outages at Kenilworth, Selkirk and Naval Training Center reduced availability though they did not have a significant impact on results; the scheduled maintenance outage at Oxnard did not have a significant impact on availability but it reduced Project Adjusted EBITDA.

Generation declined 17% from the fourth quarter of 2015. Reduced dispatch at Frederickson due to mild weather and higher availability of hydro in the region was a significant driver. However, this did not have a significant impact on our financial results as Frederickson receives most of its revenue in the form of capacity payments. Lower water flows at Curtis Palmer were another factor, although this was partially offset by higher water flows at Mamquam.

<u>Slide 7: Operations Update</u>

On January 9, we announced our intention to put our Kapuskasing, North Bay and Nipigon plants in Ontario into a lay-up mode, or a non-operational status, based on revised contractual arrangements under which we will receive fixed monthly payments without any delivery obligations. As of this week we have completed putting all three plants into lay-up. The plants are now staffed with a minimal number of technicians. Although there were costs involved in this transition, primarily in the form of severance, we expect there to be significant cost savings over the balance of the year.

This year we plan to undertake the necessary work on our Tunis project, also in Ontario, to return it to service in 2018 under the 15-year PPA that was signed in December 2014. This involves maintenance work on the gas turbine and other systems which have not been operating since the plant was laid up in early 2015. We expect most of the cost, or approximately $7 million, to be incurred and expensed this year. Although this represents our current thinking on timing, scope and cost, we remain in discussions with the relevant parties in Ontario, as discussed in our January 9, 2017 press release, on potential other initiatives that could be beneficial to ratepayers as well as to us. This could affect Tunis or our other Ontario projects.

In addition to the work at Tunis, we have several other significant maintenance projects planned for this year, including the third and final gas turbine upgrade at Morris, which is part of our optimization program; a major gas and steam turbine outage at Frederickson; major turbine maintenance at Orlando and a steam turbine overhaul at Kenilworth. We expect to undertake all of these in the early to late spring. Overall, though, including the Tunis project, we expect our maintenance expense in 2017 to be approximately level with last year, which included an extended outage at Morris.

Our optimization program, which began in 2013, has been very successful. A few highlights:

- Through 2016, we invested a total of approximately $25 million, and we expect to invest another $1 to $2 million this year.
- We realized a cash flow benefit of approximately $8 million from these investments in 2016, which was lower than our original expectation because of strong waste heat (early in the year), which reduced the need for the duct burners and booster pump at Nipigon, and because of low water flows at Curtis Palmer, which reduced the volumes running through the upgraded turbines.
- We expect this to grow to approximately $12 million this year, including the incremental benefit of the third turbine upgrade at Morris and assuming normal water flows at Curtis Palmer. This includes recognizing the full benefit at Nipigon under our revised contractual arrangement with the Independent Electricity System Operator or IESO.

As we discussed last quarter, although we will continue to look for additional optimization projects, this year we will be shifting our focus to two other areas where we expect the operations organization to have a leading role – engineering and operations support for PPA-related investments, such as the work at Tunis and possibly at other facilities to the extent that we are successful in extending PPAs elsewhere; and an aggressive initiative to analyze, identify and achieve cost savings. As part of this process we will be benchmarking our operation and maintenance costs as well as our efficiency, and evaluating many of our operational practices such as maintenance intervals and operations parameters with a view toward implementing best practices wherever feasible. We expect to have more to report on this later this year. One step that we have already taken is to eliminate one level of management between the SVP Operations and the plant managers, such that the plant managers now report directly to the SVP Operations. This flattening of the organization was done not only to reduce costs, but also to allow more direct contact with plant managers and their teams.

Joseph E. Cofelice – Atlantic Power Corporation – EVP Commercial Development

Slide 8: Commercial Update: Power Market Environment

As we've discussed on previous conference calls, most of our markets, including those in both the U.S. and Canada, are in oversupply, resulting from weak historical and projected demand, new gas plant build (partially driven by the availability of low-cost capital) and public policy preference for renewables, which continue to expand their market share. Low natural gas prices, both current and projected, have also been a significant factor contributing to low power prices and low forward pricing curves. The combination of renewable energy penetration, new gas plants and low gas prices has resulted in spark spread compression in many markets. Not surprisingly, capacity prices are also low, as evidenced most recently by disappointing capacity auction results in NEPOOL and PJM, where prices cleared well below expectations. Although this is a cyclical business and we believe that we are at the low end of the cycle, it's unclear how long these conditions will persist. For the past few years we have been focused on ensuring that the Company has the ability to withstand the down part of the cycle, because we believe that at some point markets should appropriately value dependable and flexible generation necessary to provide grid reliability and support continued renewable penetration.

To be clear, the impact of these conditions on our results in the near term is modest, as most of our plants are under PPAs with little commodity sensitivity. We have merchant exposure at Selkirk and to a degree at Morris and some market price sensitivity at Kenilworth and Chambers, but our other plants sell power under PPAs with little or modest sensitivity to fuel prices or market conditions. Even those such as Frederickson and Manchief that are dispatchable in response to market conditions earn the majority of their margin in the form of capacity payments.

Our sensitivity to current market conditions is mostly with respect to expiring PPAs, where current and expected market prices affect our ability to renew the PPA as well as the economic terms of renewal. Over the next five years, or through 2021, we have nine projects representing 25% of our capacity and 30% of our 2016 Project Adjusted EBITDA for which the PPAs are scheduled to expire. I'd like to provide an update on how we're approaching these expirations in three key markets, which cover seven of the nine projects.

Slide 9: Commercial Update: PPA Expirations (Ontario)

Ontario is in oversupply, due to weak demand and a renewables-driven oversupply of generating capacity. This has created an economic environment where the market price of power generally is insufficient to support PPA contract extensions, for us or other Non-Utility Generators. Furthermore, with the implementation of Ontario's Cap and Trade Act on January 1, 2017, we would have incurred approximately $6 million of greenhouse gas costs in 2017. Our commercial team took an innovative approach to the situation. The resulting agreement that we announced on January 9 of this year for Kapuskasing, North Bay and Nipigon produced benefits for all parties – it improves our economics in 2017 (and for Nipigon, into October 2018 at least) versus continuing to operate the plants under the existing PPAs, because of cost savings and other factors; it provides savings for ratepayers as a result of avoided fuel costs; and it lowers greenhouse gas emissions, which is an important goal for the Province. As earlier mentioned, by putting all three plants into a non-operational state we have preserved our ability to return Nipigon to service as planned in late 2018 and our option to return Kapuskasing and North Bay to service in the event that market conditions improve in the future, an event that we believe is unlikely to occur in the next year or two.

Lastly, as we've indicated previously, we continue to have discussions with the relevant parties in Ontario with respect to our plants on other potential initiatives that would produce ratepayer savings while also being beneficial for us.

Slide 10: Commercial Update: PPA Expirations (San Diego)

The market story in California is similar to Ontario in some respects, with weak demand, an oversupply of generation and aggressive renewable energy targets for the utilities. One important difference is that our three projects in the San Diego area, if re-contracted, could help utility customers achieve Combined Heat and Power (CHP) and Greenhouse Gas (GHG) Reduction targets that were committed to in a 2010 settlement with the California Public Utilities Commission (CPUC). For this reason, we consider the prospects of reaching an agreement with a utility customer on a PPA for one or more of these projects to be better in the near term in San Diego than in Ontario.

Before discussing the current status of our negotiating efforts, a review of our existing contracts may be helpful. We have three projects (Naval Station, North Island and NTC/MCRD) located on Navy or Marine bases in the San Diego load pocket. San Diego Gas & Electric (SDG&E) is the utility customer under PPAs which expire in December 2019. The Navy takes steam under contracts that also provide us the right to use the property on which our plants are located. As we've previously disclosed, the contracts with the Navy expire in February 2018, which is 22 months earlier than the PPA expiration. All three projects are qualifying facilities (QFs); production and sale of the steam at certain threshold levels is necessary to maintain QF status. Once the steam contracts end, our right to use the property ends, unless we reach agreement on an extension or a new contract with the Navy. If a project were to lose its QF status, the PPA with SDG&E could be terminated ahead of its December 2019 expiration date; in addition to the loss of EBITDA, we could incur potential liabilities, subject to our ability to mitigate these.

For the past couple of years, we have been talking with the Navy about extending the steam agreements to close the gap with the expiry of the PPAs. Although we had expected the Navy to continue taking steam from one or more of the projects, at the present time the Navy is not interested in continuing to take the steam after February 2018. Instead, last month it issued a solicitation for use of the property for energy security and resiliency using the existing sites at Naval Station and North Island. We have been participating actively in this process and intend to respond to the solicitation, which if successful would provide us with the right to continue using the property after February 2018. There has been no solicitation issued as yet for NTC/MCRD, which is on a Marine base.

On the PPA side, we have participated in various solicitations by SDG&E, and we are in different stages of negotiation on PPAs for two of our projects. In addition, we believe that there are other potential offtakers for these projects, including Southern California Edison, which also has GHG reduction targets to achieve. Clearly, any new PPA would be dependent on our gaining site control with the Navy and would be subject to CPUC approval. As we've said, the market for utility PPAs is challenging. Given current market conditions, we expect that the EBITDA under a new PPA would be materially lower, perhaps on the order of two-thirds lower as compared to the existing PPA. This still would represent an attractive return on the incremental investment needed to reconfigure and perform major maintenance on the facility. Also, a PPA of intermediate length could serve as a bridge to potentially better power market conditions down the road and preserve the long-term optionality of the plants.

Although we believe that we've made progress on the key issues affecting the renewal of one or more of these PPAs, we are not there yet, but we've also got a year to go before the expiration of the steam contracts. The outcome and timing of potential developments is uncertain. To the extent that we can, we plan to keep you updated on our progress.

Slide 11: Commercial Update: PPA Expirations (Williams Lake)

We have discussed the Williams Lake project on past conference calls. Discussions with BC Hydro on an extension of the PPA are continuing, but seem unlikely to result in a long-term extension of the PPA prior to the resolution of BC Hydro's Integrated Resource Plan or IRP, which is not expected prior to late next year. A short-term extension is possible, but uncertain.

Biomass plants, and Williams Lake in particular, have been a reliable source of clean power for BC Hydro for more than two decades. We believe the combination of the plant's significance to the local economy, strong reliability track record, operating flexibility and fuel diversification strategy improves Williams Lake's chances for obtaining a contract extension from BC Hydro. There has been strong support for the project to date from many interested parties across the province.

Last September we received an amended air permit from the Ministry of Environment that would allow us to install a new fuel shredder to burn a mix of up to 50% rail ties. Burning rail ties and other alternative fuels, along with traditional fuels, will help Williams Lake remain a low-cost producer of energy, improve our recontracting chances, and provide environmental disposal benefits. Several appeals have been filed with the Environmental Appeal Board of the air permit amendment and the corresponding landfill permit amendment. The Board has consolidated those appeals with respect to each permit and it is expected that it will consolidate the two permits for the hearing. The schedule for the appeal may be issued in the near term, although the appeal process itself may take on the order of nine to twelve months. We believe that we have a strong position and that ultimately the permit will be upheld. As a reminder, though, the fuel shredder investment would be required only if we reach agreement on a long-term extension of the PPA that provides us the ability to recover our investment in the new shredder and earn a reasonable return.

My remarks have focused on the prospects for plants with PPAs expiring in the next few years. Although it's too early to discuss issues affecting plants with longer-term PPAs, we have evaluated the competitive positioning of all of our plants, including their prospects for renewal, and categorized them internally as Tier 1, Tier 2 and Tier 3. Although for competitive reasons we are not disclosing the entire list of plants in each tier, it may be helpful to describe the criteria and provide an example or two of plants in each tier.

Tier 1 includes plants with remaining long-term contracts such as Morris (2034), or with good long-term prospects for renewal because of low marginal costs (such as the four hydro plants) or with a competitive position on the dispatch curve (Orlando).

Tier 2 includes plants where the renewal prospects aren't as strong as Tier 1, but there are solid reasons that the plant has an economic future. Tier 2 plants include Williams Lake, for reasons discussed previously, and Kenilworth, which provides benefits to the host customer (Merck).

Tier 3 includes plants operating in a more challenging environment that would require significant changes in the landscape. The Ontario plants are included in this tier.

A few brief remarks on growth before closing. At Atlantic Power, we have a management team that has a long and successful track record of growing power businesses. Until recently, however, the Company has not had the financial strength to credibly pursue growth. We now believe we have the capacity to consider modest investments, but the wholesale power market is for the most part still frothy.

One key trend that we've observed is that wholesale power prices have come down significantly but industrial customer rates have been sticky. Organic development of new long-term contracted plants with industrial customers (under which we would sell heat and power) is expected to provide a better risk-return profile than wholesale market opportunities. We have expertise in this area, including operations, fuel supply management and knowledge of merchant power markets, as well as strong relationships with industrial customers at several existing sites. The smaller size of the projects would also fit better with our capital availability. We're in the early stages of implementing this strategy, and we don't expect to have anything concrete to report for a while.

Terry Ronan – Atlantic Power Corporation – EVP & CFO

Slide 12: Q4 2016 Accounting Issues

As previously reported, during the third quarter of 2016 we undertook an event-driven impairment test because of a decline in long-term power price forecasts. The result of that test was an $84.7 million impairment charge. However, we were still required to conduct our annual impairment test in the fourth quarter. As a result of that test, we recorded an impairment charge of $1.2 million at Moresby

Lake, which represented a full impairment of the remaining goodwill at that project. Remaining goodwill on our balance sheet as of December 31, 2016 was $36.0 million, including $29.1 million related to Curtis Palmer.

As we announced in early January, we reached an agreement to terminate the existing PPAs for Kapuskasing and North Bay ahead of their December 2017 expiration dates. As a result of this agreement, in the fourth quarter of 2016 we accelerated the amortization of the remaining intangible assets associated with the PPAs at the two projects. This resulted in additional amortization expense of $12.7 million.

Note that the goodwill impairment and accelerated amortization are both non-cash charges.

As disclosed in our 2016 year-end report on Form 10-K, we have successfully remediated the material weakness finding disclosed in our 2015 Form 10-K. We developed and implemented new control procedures over goodwill impairment testing, and successfully tested these procedures during our annual goodwill impairment test in the fourth quarter.

Slide 13: Q4 2016 Project Adjusted EBITDA bridge

We reported $42.3 million of Project Adjusted EBITDA for the fourth quarter of 2016, a decrease of $8.1 million from the $50.4 million reported for the comparable 2015 period. The result was lower than our expectations primarily because of lower water flows at Curtis Palmer, significantly lower waste heat and turbine maintenance expense at Kapuskasing, Nipigon and North Bay, and severance expense at the same three Ontario plants as a result of their changed operational status. In addition, we had a scheduled maintenance outage at our Oxnard facility in the fourth quarter. These and other negative factors were partially offset by higher water flows at Mamquam and receipt of a fuel reimbursement at Kenilworth.

Slide 14: Full Year 2016 Project Adjusted EBITDA bridge

For the full year, we reported $202.2 million of Project Adjusted EBITDA, which was $6.7 million lower than the 2015 level of $208.9 million. (The 2015 result excludes the Wind businesses, which were sold in June 2015.) The 2016 result was also approximately $3 million below the lower end of our 2016 guidance range of $205 to $215 million, primarily because of the lower water flows at Curtis Palmer, lower waste heat and severance expense that occurred in the fourth quarter.

The primary contributors to the decline from 2015 were a $10.1 million reduction at Morris due to the extended outage in the third quarter of 2016, lower water flows at Curtis Palmer, and a $7.6 million decrease at our Ontario projects due to lower waste heat, fuel cost escalators and a contractual price adjustment at Calstock. The stronger U.S. dollar had a negative non-cash translation impact of approximately $2.9 million for the year, most of which occurred in the first quarter. These negative factors were partially offset by a $7.2 million increase at Manchief, which had a major gas turbine outage in 2015, and a $6.7 million increase at Mamquam due to higher water flows.

Although not included in Project Adjusted EBITDA, corporate G&A expense decreased $6.8 million to $22.6 million from $29.4 million in 2015. The reduction was primarily attributable to reduced compensation expense, lower professional services costs and lower rent expense.

<u>Slide 15: Cash Flow Results</u>

Cash provided by operating activities of $19.9 million in the fourth quarter of 2016 was in line with the year-ago figure of $19.7 million. Lower Project Adjusted EBITDA and slightly higher cash interest payments were mostly offset by favorable changes in other operating balances. During the quarter we repaid $15 million of our term loan and amortized $3 million of project debt. We also made capital expenditures of $0.7 million and paid preferred dividends of $2.1 million. These uses were approximately covered out of our operating cash flow. We also used $5.8 million of our discretionary cash to repurchase 2.4 million common shares during the quarter under the normal course issuer bid or NCIB.

For the full year 2016, cash provided by operating activities totaled $111.8 million, an increase of $24.4 million from the 2015 level of $87.4 million. The increase was primarily attributable to lower cash interest payments of $29.3 million due to debt repayment in 2015 and 2016 and the absence of make-whole premiums incurred in 2015. A favorable change in other operating balances and the $6.8 million reduction in corporate G&A expense were the other main drivers. These positive factors were partially offset by the $6.7 million decrease in Project Adjusted EBITDA and the loss of $21.9 million of operating cash flow from the Wind businesses, which were included in the 2015 result.

We used $96.5 million or 86% of our cash provided by operating activities to pay down our term loan ($85.5 million) and amortize project debt ($11.1 million). We made $7.2 million of capital expenditures and paid $8.5 million of preferred dividends. In total these uses required all of our operating cash flow. We also allocated $19.5 million of our available cash to repurchase 8.0 million shares during the year under the NCIB at an average price of $2.42 per share.

Of note, our previous NCIB expired on December 28, 2016. We implemented a new NCIB effective December 29, 2016. Under the new NCIB, we may (but are not required to) purchase up to 10% of the public float of our outstanding common shares and convertible debentures and up to 5% of the amount issued and outstanding of Atlantic Power Preferred Equity Ltd.'s preferred shares. We did not make any purchases under the new NCIB in the fourth quarter of 2016.

Slide 16: Liquidity

At December 31, 2016 we had liquidity of $204 million, including approximately $86 million of unrestricted cash. This is essentially unchanged from the September 30th level of $205 million, with a $7 million reduction in letter of credit utilization mostly offsetting the $8 million reduction in unrestricted cash. During the quarter we used $5.8 million for common share repurchases, as previously discussed. Approximately $60 million of the cash is at the parent; holding aside approximately $10 million for working capital purposes, we had about $50 million of discretionary cash at year end 2016.

Slide 17: Progress on Debt Reduction and Leverage

Our year end 2016 consolidated debt was $997 million. In the second quarter of the year we refinanced and upsized our term loan by $252 million. By year end we had offset nearly the entire increase in debt as a result of continued amortization of our term loan and project debt (totaling $96.5 million) and approximately $191.5 million of principal reduction of our convertible debentures through the NCIB, a redemption of the 2017s at par in June and a substantial issuer bid for part of the 2019s in July. On balance our debt was lower by $22 million at year end 2016 than at year end 2015 and our year end 2016 leverage ratio of 5.6 times was back to the level prior to the term loan refinancing in April 2016. (The leverage ratio is based on gross debt rather than net, and Adjusted EBITDA, which is after corporate G&A costs.)

Since year end 2013, consolidated debt has been reduced by approximately $880 million as a result of asset sales, discretionary repurchases and amortization. During that same period leverage declined from a peak of 9.5 times to 5.6 times currently. Separately, debt at our equity-owned projects has also been reduced by approximately $92 million during this same period.

Slide 18: Debt Repayment Profile

Our progress to date in debt reduction and the refinancing of our term loan and revolver has improved our debt maturity profile considerably. Slide 18 is a schedule of expected debt repayment by year, including amortization, projected repayment of the term loan and bullet maturities. Of note:

- Approximately 58% of our debt is amortizing and the rest is bullet maturities. This has reduced the amount of debt subject to refinancing risk.

- We expect to repay $100 million of our term loan and amortize $11.8 million of project debt in 2017.

- Our next bullet maturity at the parent is not until June 2019, when the remaining $43 million of Series C convertible debentures mature. We also have a project debt maturity of $54 million at Piedmont in August 2018.

- Although not shown on this slide, our corporate revolver matures in April 2021. We currently do not have any borrowings under the revolver.

- Through year end 2020, we expect to repay approximately $400 million of project and term loan debt, primarily out of operating cash flow. This represents approximately 40% of our total debt.

Slide 19: Projected Debt Balances

The $400 million of cumulative repayment from year end 2016 through year end 2020 shown on Slide 19 assumes that we refinance Piedmont in 2018 and either refinance or use our revolver for the 2019 convertible debentures (that is, no reduction in debt for either).

We're evaluating different paths to address the Piedmont maturity, including through a refinancing or a potential divestiture (Piedmont is not included in the term loan structure). With respect to the convertibles, we have not made a decision with respect to addressing these maturities, but the alternatives include repurchases under the NCIB, up to the 10% limit; calling one or both of the issues sometime between their June and December 2017 call dates and their June and December 2019 maturity dates; or a refinancing prior to maturity. We have the option of using up to $100 million under our corporate revolver to address the convertible debentures.

We expect this delevering to generate significant interest cost savings that benefit our cash flow. Repaying $400 million of project and term loan debt during this period would result in approximately $24 million of annualized interest cost savings by 2021. If we used cash to redeem all or part of the remaining convertible debentures, that would generate up to another $6 million of annual interest cost savings. Lower cash interest payments can help to offset the impact on our cash flow from potential reductions to EBITDA resulting from PPA expirations during this period.

Delevering remains one of our most important financial goals. Although required debt amortization in 2017 is only $112 million, which will be funded out of our operating cash flow, we plan to allocate $40 million or more of discretionary cash for additional debt reduction (which could include repurchasing or redeeming convertible debentures, further paydown of term loan or project debt). This would bring total debt repayment in 2017 to $150 million or more.

Although we have not shown projected leverage ratios on this slide, we believe that, assuming debt repayment of $150 million, we will be approximately 4 times levered by year end 2017 as compared to 5.6 times currently. By the end of 2020 we expect to be less than 4 times levered, or close to what we view as an appropriate level of leverage for this business.

Slide 20: 2017 Guidance: Project Adjusted EBITDA bridge vs. 2016 actual

The Company has not provided guidance for Project income or Net income because of the difficulty of making accurate forecasts and projections without unreasonable efforts with respect to certain highly variable components of these comparable GAAP metrics, including changes in the fair value of derivative instruments and foreign exchange gains or losses. These factors, which generally do not affect cash flow, are not included in Project Adjusted EBITDA.

Our 2017 guidance range for Project Adjusted EBITDA is $225 to $240 million. At the midpoint, this represents an approximate $30 million increase from the 2016 actual result of $202 million. The most important contributor to this increase is the expiration at year end 2016 of two above-market contracts to supply gas to our Kapuskasing and North Bay projects in Ontario. These contract expirations were unrelated to the revised PPA arrangements that we announced in January. The benefit to this year's EBITDA of approximately $26 million represents the difference between incurred fuel costs in 2016 and the fuel credit provided to the customer under the Enhanced Dispatch Agreements for both plants. Note, even if we had continued to operate the plants under the PPAs this year, we still would have received the same benefit to EBITDA as we would have purchased gas at a market price, resulting in savings versus the above-market cost incurred in 2016.

The other factors affecting our guidance are less significant but include:

+ Forecasted return to average water flows, which would result in increased EBITDA from Curtis Palmer, partially offset by a decrease from Mamquam;
+ Full year return on optimization investments, including the final turbine upgrade at Morris to be completed this spring;
+ Lower maintenance expense and higher revenues at Morris, which had an extended scheduled outage in 2016;
+ Lower operation and maintenance costs at the three Ontario plants which we put into lay-up, net of related severance and other costs;
– Maintenance expense required to prepare Tunis for a return to service in 2018 under the terms of the PPA, and
– Maintenance expense at Frederickson related to a scheduled major gas and steam turbine outage.

Our 2017 guidance does not include any current or retroactive payments from the Ontario Electricity Financial Corporation (OEFC) or the IESO in conjunction with the Global Adjustment lawsuit brought by a group of Non-Utility Generators, which was decided in favor of the plaintiffs in 2015. The lawsuit concerned the calculation of a price escalator for power sold to the OEFC under certain PPAs. In January 2017, the Supreme Court of Canada denied OEFC leave to appeal the ruling. Although we were not a party to the lawsuit, we have a standstill agreement with OEFC that reserves our right to bring claims against the OEFC with respect to the price escalator calculation in the PPAs for our Kapuskasing, North Bay and Tunis projects. Earlier this week, we were notified by the OEFC that they intend to make a payment to us with respect to 2016 for Kapuskasing and North Bay. We are in the process of reviewing this notice.

Slide 21: 2017 Guidance: Project Adjusted EBITDA bridge to Cash Provided by Operating Activities

Slide 21 provides a bridge of our 2017 Project Adjusted EBITDA guidance range of $225 to $240 million to Cash provided by operating activities of $130 to $145 million. For purposes of this bridge, the impact of changes in working capital on cash flow is assumed to be nil. The implied increase in Cash provided by operating activities from the 2016 level of $111.8 million is approximately $26 million, using the midpoint of the 2017 range. As noted on Slide 21, we expect a modest further reduction in cash interest payments this year.

Planned uses of operating cash flow in 2017 include $100 million amortization of our term loan; $12 million of project debt amortization; $5 million of capital expenditures, mostly consisting of the Morris turbine upgrade and a few other small projects; and $9 million of preferred dividend payments. We expect to have modest cash flow remaining after these uses that would be available for discretionary purposes. As previously noted, we plan to allocate $40 million or more of our estimated discretionary cash to additional debt reduction in 2017.

Depending on resolution and collection of OEFC revenues associated with the Global Adjustment dispute, there could be additional cash available to us. The timing and amounts are uncertain, but we would expect to prioritize use of these funds for additional debt repayment beyond the $150 million commitment for this year.

The Company is not providing specific 2018 guidance at this time. However, Project Adjusted EBITDA for 2018 is expected to decline from the 2017 guidance level primarily due to the expiration at year end 2017 of the Enhanced Dispatch Contracts for Kapuskasing and North Bay. Project Adjusted EBITDA may also be affected by the outcome of negotiations with respect to PPAs or other contracts that are scheduled to or which may expire in 2018.

James J. Moore, Jr. - Atlantic Power Corporation – President & CEO

Slide 22: How We Think About the Business

In managing this business and making capital allocation decisions, we try to think and act like a family that has 100% of its net worth invested in the business and is in it for the long haul. We are not focused on quarterly results. We are not focused on GAAP earnings. We don’t try to promote the shares and we don’t focus on how to “surface value” or otherwise move the share price. We are focused on the free cash flow generated by our business. We are focused on building intrinsic value per share. Our belief is that if we run the business like owners and build value, the share price will reflect that value over time.

Now we understand, and so should you, that this is a tough business. Power generation is a capital-intensive, cyclical, commodity-priced and heavily government-regulated activity. (I told you we aren’t promotional.) The way that we (members of the management team) have made money in the energy business since 1982 and in power since 1986 has been to be mindful of the cyclical nature of the business and to use the market’s near-term overreactions to our advantage when investing, buying or selling assets or businesses. During the course of my career, I have been involved in the sale of IPP businesses three times, the sale of a quarter of the assets of a business twice and in one of the largest spin-offs in the international power business.

Today U.S. IPP shares trade near historic lows. Atlantic Power stock (NYSE) hit an all-time low in December 2015, but traded up 27% in 2016 while the shares of the three largest U.S.-focused IPPs traded up 6%, down 21% and down 37%. Relative performance in a terrible market is cold comfort to owners. The stock closed at $2.71 the day before I joined the company (in January 2015), so I have nothing to brag about. After two years of intense restructuring and painful cost-cutting, the result is a lower share price. In February of last year, when the stock was at $1.68 (which was not much above the all-time low of $1.60), we announced the elimination of our common stock dividend in order to boost liquidity for higher value-added purposes, including repurchasing debt and common shares. Since we announced that decision, the Company has bought and canceled 8.1 million shares at an average price of $2.42. The nearly $20 million we invested in repurchases represents almost two years of the previous dividend payment. We made this investment because the shares were trading at a meaningful discount to our estimates of intrinsic value per share. If we can buy shares at estimated returns that are higher than the returns available from external growth we want to do so, even though we are shrinking the balance sheet rather than growing the absolute size of the business. The limiting factor on our share purchases is that we are committed to reducing leverage. In the type of business I described earlier, you want to be prudent on the use of debt. We have reduced our leverage, including through debt repurchases, to mitigate the downside risk to our shares.

In addition to the Company's share repurchases, since joining Atlantic Power two years ago, I have made a personal investment in the Company by buying 350,000 shares at an average price of $2.47, and insiders as a group have bought a total of 1.4 million shares at an average price of $2.31 and a high price of $3.24. These purchases were based on the belief that the shares represented a good price-to-value investment. If we believe the shares are trading above intrinsic value we will not be buying them for the Company, nor would insiders unless they were doing so to meet an ownership guideline.

We use our intrinsic value estimates to determine the overall value of the business, which helps to inform our capital allocation decisions. We do not publish our estimates. To do so might encourage investors to rely too much on what are rough estimates within a wide range that are subject to much variability.

Our intrinsic value estimates are highly sensitive to discount rate assumptions and the power market price curves that we use to estimate cash flows from our merchant plants (small) and from our contracted plants in the post-PPA period, as well as to estimate the terminal value of our hydro facilities. These forecasts of power prices are driven by the supply of and demand for power, both of which are heavily dependent on government policies and regulations along with macroeconomic factors. Natural gas prices and hostile public policy are driving coal and nuclear plant retirements on the supply side. Public policy including state-level renewable energy portfolio standards and federal tax incentives have driven the growth of intermittent sources of power (wind and solar). Although these sources are intended to lower carbon emissions, they also lower the value of, increase the costs from and make less efficient the natural gas plants that are still necessary to generate when the intermittent sources do not. The intermittent sources don't replace the need for gas plants, but they do reduce the run time of gas plants.

Although these dynamics have made natural gas plants less profitable (and therefore less valuable), the low levels of interest rates have encouraged investment funds and others to continue building these plants into an over supplied market in the hope that retirements (primarily of coal and nuclear) will outpace additions.

Our experience has been that when the markets are pessimistic, they assume that conventional power plants are no longer needed and they price them accordingly. When markets are optimistic, particularly on wind and solar, they become exuberant and these assets are priced accordingly.

Today there is a large disparity between IPP share prices in the United States and prices for the underlying power assets, particularly those backed by PPAs with a long remaining life. So in 2015 we sold $350 million of contracted wind plants and we will consider at least one further asset sale in 2017. Over the past two years, we have bought in nearly $20 million worth of shares and repurchased or redeemed approximately $533 million of debt.

That all might sound like a business that ought to be sold. As noted before, I have been involved in six transactions where a large portion or all of the IPP business has been sold or spun-off. At Atlantic Power we have sold off five plants, another sale is being contemplated and we have mothballed another four plants to maximize the cash flow to shareholders via debt and equity repurchases. That is a total of nine or ten plants out of 28. When power prices are down 40% to 50% and IPP shares are trading near all-time lows, it is not an opportune time to obtain fair value (much less a premium) on a sale of the entire business.

Please don't read the above as we are running the business to get it ready to sell. I'm merely making the point that the management team has a long track record of selling assets and businesses when prices are compelling compared to the value to be realized from holding or growing the business. We are trying to be as rational as possible in our capital allocation.

In the near term we see share prices as depressed and the sector in distress while low interest rates have kept PPA-backed asset values elevated. We are buying in the former market and selling in the latter market. We may be wrong on both counts. Our estimates on intrinsic value could be wrong. Power prices may go lower and stay lower for longer than we anticipate. Low interest rates might last longer than people think, and the returns on contracted assets can be compelling in that environment. If we didn't believe it was prudent to continue delevering the balance sheet, we would be buying in shares more aggressively. We try to take a balanced approach in deciding whether to allocate excess liquidity to reducing debt (to further derisk the Company) or to repurchasing shares at a discount (to increase the value per share for remaining shareholders).

Slide 23: Different Scenarios and How They Affect the Value of Atlantic Power

Let me lay out some broad scenarios for the future and how we think they might affect the value of Atlantic Power.

LOWER FOR LONGER:

This is a cyclical business and our experience has been that to make money requires being countercyclical in capital allocation. It might be different this time. Conventional power assets are not favored, at least not from a policy perspective in many states. Continued build out of intermittent sources of power driven by state policies and federal tax subsidies may continue to diminish the value of conventional power plants for a longer period than makes pure economic sense.

In that case an owner of such assets has two choices – sell, or hunker down in order to survive to a point in the future when, for example, the treatment of natural gas plants becomes more favorable or when the volatility in the markets provides a full price.

Thinking like owners with a long-term orientation means that we have focused on protecting the downside first. Our total debt, including our share of debt at equity-owned projects, has been reduced by nearly a billion dollars since year end 2013. Our corporate overhead has been reduced by nearly 60% from $54 million to $23 million from 2013 to 2016. Our interest expense has been reduced by $60 million over that period. Our credit ratings have been adjusted upwards. We have lengthened our debt maturities. We have liquidity of more than $200 million, which includes $86 million of unrestricted cash (including $60 million at the parent) and borrowing capacity of $118 million under our revolver.

All this debt and cost reduction has been painful. We closed offices and laid off employees. We moved the headquarters from the Financial District in downtown

Boston to the suburbs in Dedham, Massachusetts. Having come through two years of restructuring we have the financial strength to avoid fire sales of assets. We are well positioned to address our maturities through 2019 and we expect to have repaid more than 80% of our term loan by its maturity in 2023.

In terms of PPA renewals, this hard-won financial stability has allowed us to be patient rather than being pressured to execute renewals on any terms. We appreciate that investors want to know the likely outcome of PPA renewals, but these require patience and discipline on our part to try to achieve the best outcome possible in a market where power prices have fallen to very low levels relative to both historical and new build prices. Our Morris PPA renewal was a good outcome for the Company and is modestly accretive to EBITDA versus the existing PPA terms while providing our customer with good terms and benefits. That was a win/win. As Joe Cofelice outlined earlier, our Ontario renegotiation was a creative effort by the commercial team to respond to the supply and demand situation in that Province while lowering gas costs for customers and greenhouse gas costs for the Company. That result produced benefits for all parties. In San Diego, the run rate for any new PPA will be quite a bit lower than that under the previous arrangement, reflecting current market conditions. However, assuming that we are able to renegotiate agreements with the U.S. Navy (which we cannot predict), we would expect that if we are successful in executing a new PPA in San Diego, it will provide us the ability to make incremental capital investments at returns well in excess of what we could realize from other uses of capital, either externally or internally.

Although we have reduced debt and overhead costs by a considerable amount already, we are still grinding away on corporate G&A and plant operation and maintenance expense (O&M). The plant O&M is a challenge as our plants have smaller sizes on average than the larger IPP companies. Our smaller, older on average and geographically scattered fleet makes O&M cost benchmarks more difficult to achieve versus larger, newer and less disperse fleets. On corporate G&A, we think we are very efficient in terms of G&A dollars per plant. Again, on a per MW basis it is more challenging. If we have 23 plants at approximately 90MWs each on average and we increased the average plant size to 350 MW, there would be little in the way of necessary corporate overhead increases required to handle larger-sized plants. As a percentage of revenue our G&A costs have been driven down from 8.6% in 2013 to less than 6% today. We have reduced our revenue by 36% in the course of the asset sales noted above, which normally would provide negative operating leverage, but we have been so aggressive on costs that they have come down by 58%, more than the 36% reduction in revenue.

In the short term, then, we have focused on mitigating our downside risk through aggressive debt and cost management, which also buys us time to be patient on PPA renewals and asset sales. If the power markets remain low, we can mitigate the impact on our cash flow from expiring PPAs through cost reductions. For example, in 2016 we had $60 million of Project Adjusted EBITDA from projects with PPAs which are scheduled to expire in the next five years. We believe that we can offset approximately half of that potential reduction in cash flow from cost and interest expense reductions in a worst-case scenario where none of those PPAs are renewed. We can to continue to pay down debt in that scenario. We would end up with a smaller EBITDA but also with lower leverage at an acceptable level for this business. In addition, we still would have good value in the post-PPA periods for our hydro and other strategically well positioned assets as outlined by Joe. This is a long slog scenario. It is not our base case. The point is that despite a challenging PPA environment, we believe that our work on debt and costs have positioned us to endure an extended down cycle. Looking at it like owners of a family business, we believe we have taken out the risk of falling over a cliff and we now have the ability to protect our legacy assets.

BASE CASE:

In our base case we think that power curves will be higher than the current ones but lower than they were only a few quarters ago. We don't assume a return to the prices of a few years ago, and we do not assume that all of our gas and biomass plants are recontracted. For example, we do not assume that any of our assets in Ontario are recontracted, and we assume there is a significant reduction from our San Diego projects post-PPA. We also make assumptions with respect to the terminal values of our assets, which is well into the future. The most significant component of our terminal value is our hydro facilities, which we expect will have strong cash flow after their PPAs expire, and based on transaction multiples for other hydro assets, have significant long-term value.

In that scenario our estimate of intrinsic value is higher than in the LOWER FOR LONGER scenario above. In both scenarios, our estimate of intrinsic value is higher than our share price is today.

REFLATION:

As I noted above, a move in the forward curves shifts the intrinsic value of our shares significantly because of the impact on estimated cash flows post-PPA and estimated terminal values for the hydro facilities. A significant increase in power prices above our base case assumption would thus add significant value to our base case estimate, which is already above our current share price. We don't control power prices, so the key upside driver to the base case is largely outside of our control. We can protect against downsides to the best of our ability but we cannot assure higher prices for power going forward. Our job has been to insure that we can endure a LOWER FOR LONGER scenario and to be around to profit from a REFLATION scenario should it occur, while maximizing the intrinsic value of our shares by aggressive cost and debt management in the BASE CASE.

<u>Slide 24: Beginning to Implement an External Growth Strategy</u>

We have been reticent on external growth for the past two years for four reasons. First, we needed to focus on mitigating downside risks. Second, we thought the internal or organic uses of capital had higher returns than what was available externally due to where the markets were pricing assets. This was an owner-oriented decision to maximize the per share value of the business rather than trying to grow in terms of absolute size. It was the result of trying to be as rational as possible about capital allocation and market prices. Third, our financial and human resources had to be focused on restructuring. Lastly, we have been investing in power markets for more than three decades and our experience is that this is a sector with tough economics for buy and hold investors. We try to sit on the sidelines until we see compelling opportunities based on conservative return estimates in areas within our circle of competence. Charlie Munger calls this "sit on your ass" investing. Do nothing with your capital until the odds are definitely in your favor rather than attempting to be in the market all the time. When you find a good opportunity that you understand, then move quickly and decisively. That isn't the ideal profile for an investment fund seeking institutional investors. Given the small size and underfollowed nature of Atlantic Power, we have the luxury of being patient, i.e., even if we made lots of promises they would be greeted with skepticism anyhow.

In the past as a management team we have invested in QF plants, merchant CCGT, wind, biomass, solar and energy services businesses. Although growth in wind and solar installations in North America has been dramatic, the financial results have been mixed. Meanwhile, U.S. utilities are being buffeted by public policy on things like rooftop solar and extremely weak or declining electric demand growth for their remaining customers. The IPP model of selling to utilities under long-term PPAs is battered if not broken.

Morris was our first significant PPA renewal in several years. The run rate EBITDA contribution under the PPA extension with our industrial customer is more attractive than what we have seen from utilities. Understand, though, that the existing PPAs provide for a return of and on our capital to finance construction. Interest rates were much higher when they were signed. From a customer standpoint, our original investment in the plants has been recovered and therefore the cost of power from our plants should be lower on a renewal. However, for some of our plants, an extension of the PPA will require that we make incremental investment in the plant. We will require good returns on this incremental investment or we won't do those deals.

The larger point is that in the United States, the high penetration rate of intermittent power sources has kept retail rates (end-user prices) high at the same time that wholesale power prices have declined by forty percent or so in some cases. We have, therefore, shifted our focus toward the industrial markets. We are working with industrial customers at our existing facilities to provide them low-cost, reliable, clean power. We also have begun to seek new plant opportunities with other industrial customers. We think that this makes sense based on the current structure of the power markets and it is a market segment that is well within our core competencies, while the investments are of a size that will attract less interest from the large IPP players but which can move the needle for Atlantic Power. We have begun to allocate some of our people in this direction and as we proceed we may add some development expense which would be very modest in 2017. We will be putting in mostly sweat equity at this point. Depending on how things evolve, we ought to be able to give a more specific update at the end of the year.

When we worked together previously, Joe Cofelice and I were able to capture $160 million of value from private transactions by growing off a much smaller capital and resource base than we have at Atlantic Power. That isn't a forecast but it points out that here we have adequate resources and experience to grow this business. If we are successful, we would then have a fourth case which would be GROWTH to go along with the other cases. It is too early to make any promises on this front but we are very enthusiastic about this effort.

All of this probably reads more like an annual letter. I wrote it to my fellow shareholders as a year end review. If our roles were reversed, I'd appreciate the update now rather than waiting for our annual report in the spring. At that point we hope to be able to report progress on several fronts.

Non-GAAP Disclosures

Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP, and is therefore unlikely to be comparable to similar measures presented by other companies. Investors are cautioned that the Company may calculate this non-GAAP measure in a manner that is different from other companies. The most directly comparable GAAP measure is Project income (loss). Project Adjusted EBITDA is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in the fair value of derivative instruments. Management uses Project Adjusted EBITDA at the project level to provide comparative information about project performance and believes such information is helpful to investors. A reconciliation of Project Adjusted EBITDA to Project income (loss) and to Net loss on a consolidated basis is provided in Table 1 below.

Atlantic Power Corporation
Table 1 – Reconciliation of Net loss to Project Adjusted EBITDA
(in millions of U.S. dollars, except as otherwise stated)
Unaudited

	Three months ended December 31		Twelve months ended December 31	
	2016	**2015**	**2016**	**2015**
Net loss attributable to Atlantic Power Corporation	**($6.6)**	**($88.6)**	**($122.4)**	**($62.4)**
Net income attributable to preferred share dividends of a subsidiary company	2.2	1.9	8.5	8.8
Net loss attributable to noncontrolling interests	-	-	-	(11.0)
Net loss	($4.4)	($86.7)	($113.9)	($64.6)
Net (loss) income from discontinued operations, net of tax	-	1.3	-	(19.5)
Net loss from continuing operations	(4.4)	(85.4)	(113.9)	(84.1)
Income tax benefit	(0.4)	(29.9)	(14.6)	(30.4)
Loss from continuing operations before income taxes	(4.8)	(115.3)	(128.5)	(114.5)
Administration	5.0	6.4	22.6	29.4
Interest expense, net	18.2	15.8	106.0	107.1
Foreign exchange loss (gain)	(5.1)	(11.2)	13.9	(60.3)
Other income, net	-	-	(3.9)	(3.1)
Project income (loss)	$13.3	($104.3)	$10.1	($41.4)
Reconciliation to Project Adjusted EBITDA				
Depreciation and amortization	$42.7	$31.2	$133.5	$130.1
Interest expense, net	2.7	2.1	10.9	9.8
Change in the fair value of derivative instruments	(17.8)	(6.7)	(37.9)	(15.4)
Impairment	1.2	127.8	85.9	127.8
Other (income) expense	0.2	0.3	(0.3)	(2.0)
Total Project Adjusted EBITDA	$42.3	$50.4	$202.2	$208.9